In the Matter of:)
)
Rulemaking on Establishment)
Of Target Reserve Level)

Docket Number: 2002-07-01

CALIFORNIA ENERGY COMMISSION STAFF RESPONSE TO SCOPING QUESTIONS IN CALIFORNIA POWER AUTHORITY'S JULY 25, 2002 RULEMAKING ON THE ESTABLISHMENT OF TARGET RESERVE LEVELS FOR THE INVESTMENT PLAN

September 18, 2002

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The following response supplements the Energy Commission comments that were presented to the California Power Authority on September 6, 2002. The staff response provides additional details to elaborate on the issues associated with each question.

The staff also revised the total number of expected new generation projects that was referenced in the September 6th comments, changing from 11,500 MW to 9,781 MW. Staff originally included the dependable capacity of several Sempra facilities that are currently under construction in Arizona and Mexico. Considering that some of this dependable capacity from these facilities may be sold to other load centers, staff decided to instead include only the encumbered capacity associated with Sempra's power purchase contracts.

1. Considering the Fundamental Difference Between the Current Generation Market and the Past, Does the Historic Reserve Level Reflect the Greater Reliability Risks of the Present and Future?

A reserve margin (or level) is a measure of the amount of reserve capacity available to cover the possibility of system fluctuations and unexpected emergencies. The Power Authority's target reserve margin, a deterministic value, is one way to address supply-adequacy concerns. System planners, and some government agencies, historically determined a minimum reliability target probabilistically. Planners generally stated a reliability standard as the expectation that a loss of load would occur no more frequently that one day in ten years. More recently, some utilities have considered using a value-of-service approach to reliability planning.

In any case, effectively assessing how well a control-area operator's portfolio of capacity resources meets a reliability standard requires a complex and data-intensive simulation of the electricity system. A rigorous reliability analysis considers the dynamic nature of the system, diverse interconnection opportunities, facility-outage uncertainties, serious local transmission constraints, and differing load characteristics. It also considers the specific attributes that different electricity supplies or load-management options would contribute to system reliability. It should also consider how market imperfections would affect generation availability. Typically a complex analysis will find a different level of reserve requirements for each control area, rather than a single West-wide or California value. However, even the most sophisticated analysis is only as good as its assumptions.

Although the Energy Commission is well aware of the consequences of a reserve margin that is too low, a target reserve margin that is too high may also have negative consequences if met only by long-term commitments. For example, a high reserve margin may dampen investment incentives, cost more than consumers are willing to pay, and frustrate the development of opportunities (including renewables and demand response) that depend on forthcoming regulatory decisions.

As the Power Authority notes in its order, recent changes in the electricity market, and both related and unrelated changes in financial markets, have significantly affected how we might evaluate reserve margins. At the same time, the remarkable events that began in 2000 and continued into 2001 have not recurred to date. This is because significant regulatory, administrative, and legislative actions have stemmed the price volatility and market instability of that period.

Moreover, proceedings currently before the California Public Utilities Commission and the Federal Energy Regulatory Commission will dramatically alter the regulatory landscape, and the financial climate, in the very near future. These proceedings are considering significant changes in market structure, utilities' obligations with respect to resource procurement, and opportunities for consumers to participate in demand-responsiveness programs.

Even before the outcome of these important regulatory proceedings is clear, the amount of capacity under construction—and on schedule—will bring planning reserves to above 15 percent of load by 2005. The Energy Commission believes that this would provide a much-needed cushion.

2003-2005 Supply and Demand Outlook

Demand reductions by California electricity consumers, firm power contracts and new generation sources averted predicted outages and brought market stability. The electricity supply outlook for the next few years is even more favorable for maintaining reliability, assuming that many of the market-related problems are successfully resolved.

Figure 1-1 and **Table 1-1** provides a summary of the Energy Commission's "most likely" resource balance scenario. The chart includes dependable capacity available to California, subtracting some generation facilities that are expected be shut down. The new resource additions include those facilities that have long-term contracts with the Department of Water Resources and other projects that are expected to be completed. The planning reserve margin is based on the Commission's latest demand forecast, including the assumption that no more than half of the observed 2001 peak demand reductions due to conservation will persist over the next few years. The 1-in-2 demand represents the expected peak under average weather conditions. The reserve margin does not include surplus power that will likely be available for spot market imports. Given the amount of new generation development in other Western states, the Energy Commission staff expects that there will be surplus spot capacity available to sell to California over the next several years. The response to Question 2 will expand on the Commission's assessment of new generation development.

Figure 1-1

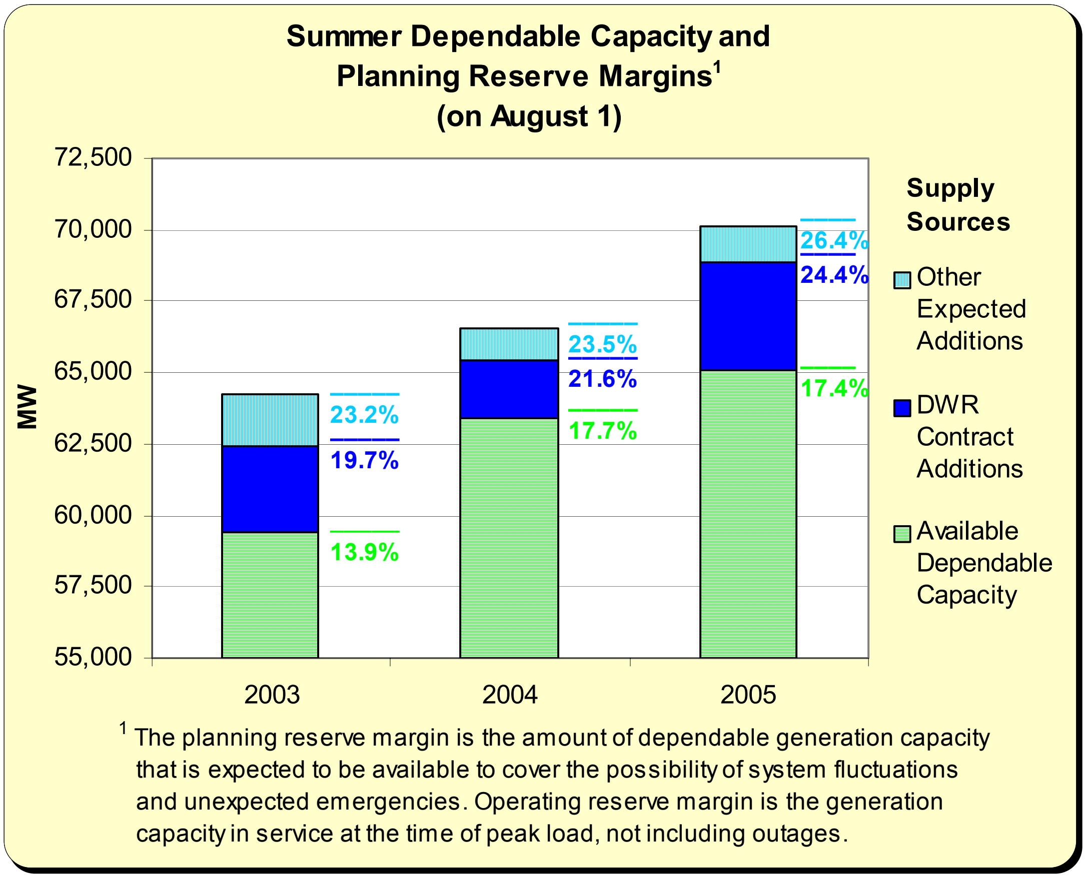


Table 1-1
Projected Peak Demand and Available Dependable Capacity (MW)

	2003	2004	2005
Average Peak Demand	52,150	53,846	55,452
Available Dependable Capacity	59,410	63,399	65,104
DWR Contract Additions	3,035	2,065	3,771
Other Expected Additions	1,824	1,060	1,212
Total Capacity by July 31	64,269	66,524	70,087

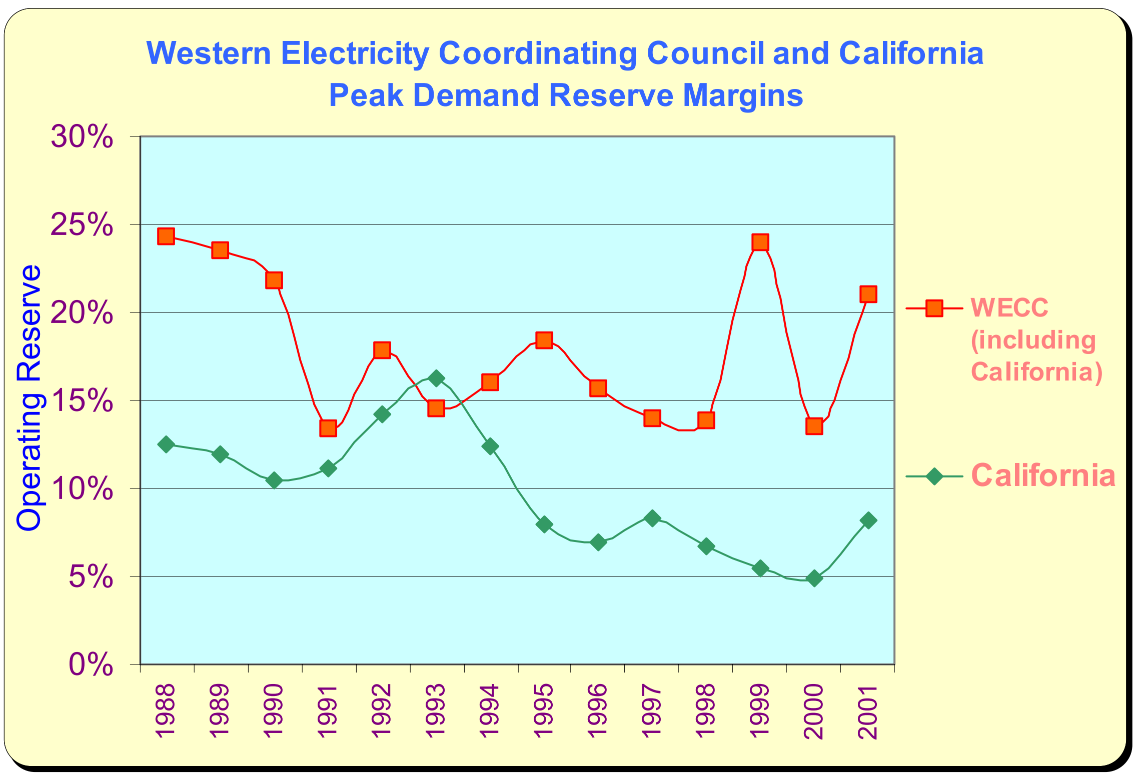
Historical Operating Reserve Margins

Since power plant development did not keep pace with load growth, operating reserve margins throughout the Western Energy Coordinating Council (WECC) region and especially in California declined over time. **Figure 1-2** shows the summer (July-August) operating peak reserve margins for California and the WECC region. The recorded reserves include operational generation, not those facilities that were down for maintenance. **Attachment 1** provides additional data on historical California trends.

The more recent California operating reserve margins include the record reported by the ISO control area. The method for calculating the margins that the ISO now reports each day differs from the WECC estimated peak reserves. The ISO daily reserves are a function of the generation that is contractually scheduled for dispatch and does not measure the actual physical availability of the total operating generation in the system.

WECC operating reserve margins improved in 1999 and 2001 because of increased generation and lower peak demand levels compared to 1998. The drop in WECC margins in 2000 was primarily due to a doubling of reported generation outages and an increase in peak demand resulting from temperature variations.

Figure 1-2



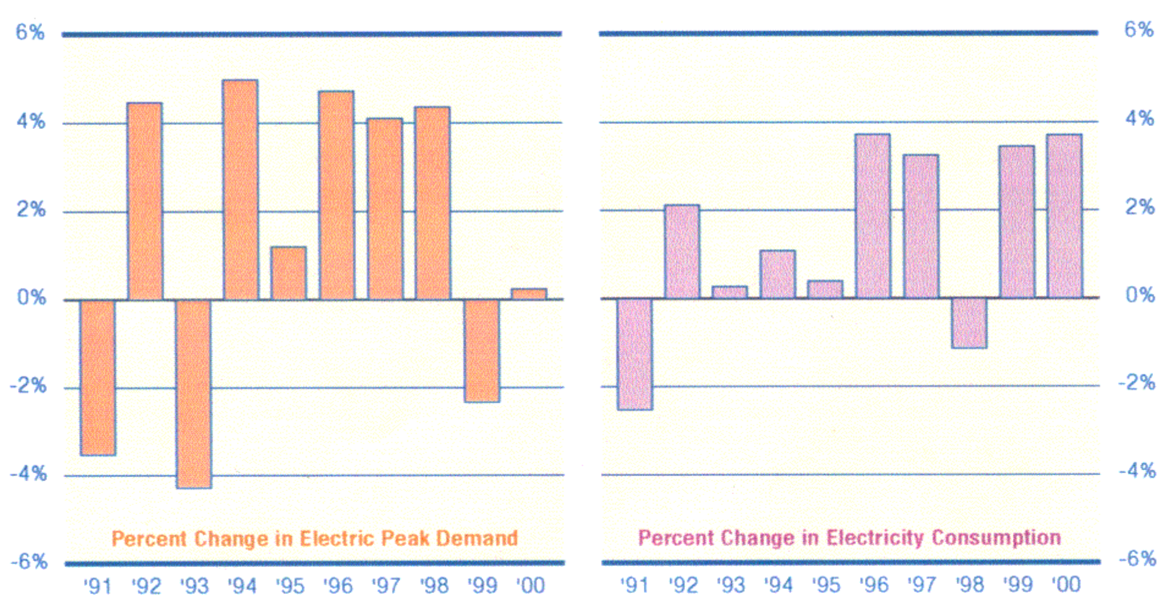
The ISO-scheduled reserve margins dropped below 1.5 percent several times during the 2000/2001-winter period. This is a very unusual development since California's winter demand levels are far lower than during the summer periods. Part of the reason that reserves dropped to low levels during the year was because of the higher-than-normal amount of facilities that were not generating and selling electricity to the ISO. There was limited generation availability during these periods in part due to financial concerns. Many Qualifying Facilities were not paid as a result of the utilities experiencing cash flow problems. Some generators also hesitated to sell electricity considering the risks that they would not be paid. Generators also claimed that they encountered high forced outage rates.

Electricity Consumption Trends

Electricity consumption increased in the Western United States because of the growing economy and population. Recent California electricity consumption and peak demand growth were no higher than trends over the past decade. Although the growth in per-capita electricity use continued to increase in both the nation (1.7 percent per year) and the West (1.2 percent per year), California per capita use has been relatively flat, growing only at 0.1 percent per year on average.

Figure 1-3

Growth in California Electricity Use not Extraordinary



As seen in **Figure 1-3**, growth in peak and energy in the last few years is not greater than growth in earlier years. For the three years preceding restructuring (1995-1997), overall electricity demand grew by seven percent—the same as the growth in the three years after restructuring. Furthermore, summer peak demand fell by two percent after restructuring, compared to a nine percent increase before.

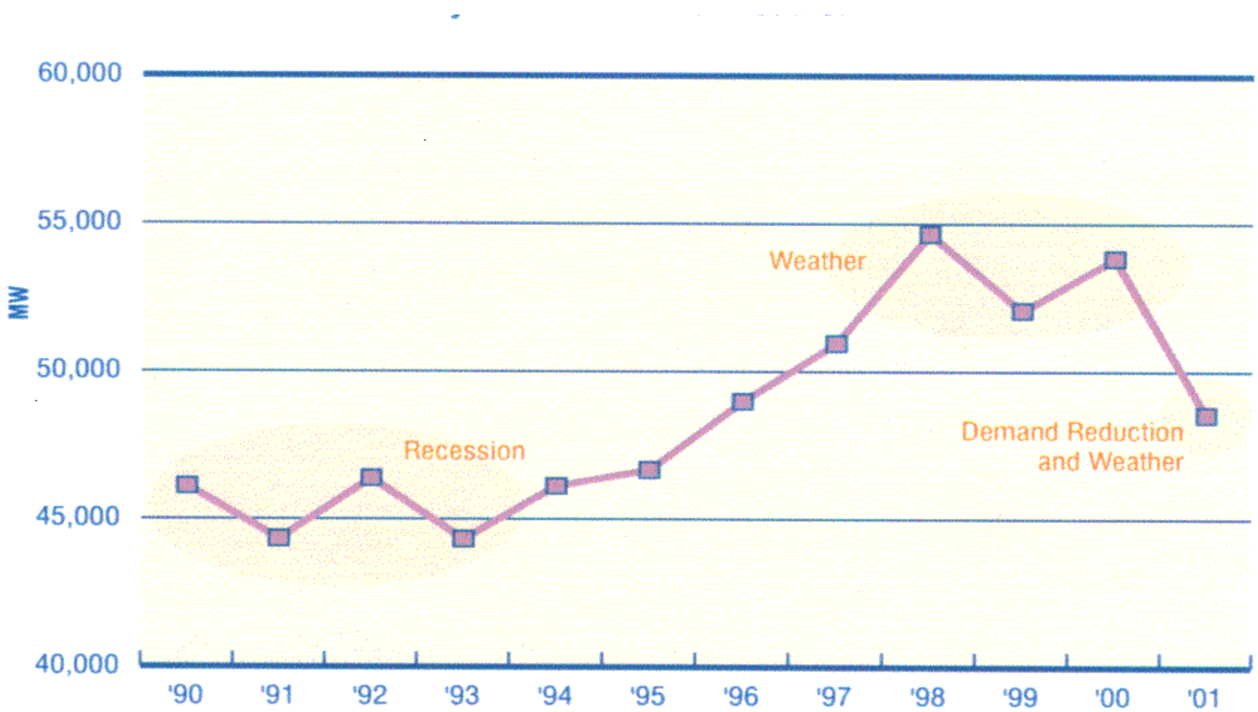
One important factor influencing electricity use, particularly peak demand, is temperature. Hot weather causes increased use in air conditioning and increased peak demand. **Figure 1-4** shows the influence of economics and weather on peak demand. The no-growth period of the early 90s was caused by an extended recession in the state. Peak demand growth in the mid-90s reflects the state's economic recovery. In addition, some small weather fluctuations can be seen – 1995 was relatively mild, 1996 hot, and 1997 mild.

In the late 1990s, weather fluctuations obscure any economic growth trends. August 1998 was the sixth hottest month ever in the state, leading to a very high peak demand. Peak demand in 1999 occurred in July, which was much cooler than normal.

The summer of 2000 was hot again, the twenty-fifth hottest out of 106 years, leading to an increase in peak demand. The summer of 2001 was as hot as the summer of 2000, the twenty-fifth hottest out of 107 years. Even though both years have similar temperature patterns, peak demand in 2001 was lower than in the previous three years. This reduction is the result of efforts of citizens of the state to reduce demand and conserve electricity.

Figure 1-4

Peak Demand Influenced by Economics and Weather



Attachment 1
Historical Coincident Peak Demand and Operating Reserve
Peak Demand on Day of Year with Highest State Peak Demand (MW)

Control Area	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Day of Coincident Peak Demand	07/22/88	07/20/89	07/13/90	10/02/91	08/17/92	08/02/93	08/15/94	07/27/95	08/14/96	08/06/97	09/01/98	07/12/99	08/16/00	8/7/01
PG&E	17,216	17,150	19,278	16,642	18,392	19,607	19,118	19,746	20,699	21,484	20,511	23,104	21,196	20,052
SCE	15,616	15,632	17,115	16,709	18,413	15,590	17,892	17,435	18,205	19,084	19,935	19,122	19,272	18,231
LADWP	4,736	4,660	5,229	5,123	5,331	4,502	4,911	4,743	5,145	5,434	5,643	5,455	5,313	4,790
SDG&E	2,523	2,506	2,799	3,027	3,355	2,697	3,137	2,931	3,282	3,491	3,960	3,606	3,316	3,137
Statewide	40,091	39,948	44,421	41,501	45,491	42,396	45,058	44,855	47,331	49,493	50,049	51,287	49,097	46,209
SMUD	1,873	1,934	2,146	1,760	2,117	2,162	2,034	2,169	2,392	2,442	2,505	2,759	2,396	N/A
CAISO	35,355	35,288	39,192	36,378	40,160	37,894	40,147	40,112	42,186	44,059	44,406	45,884	43,784	41,419
Pasadena										278	292	285	275	N/A
IID									639	626	608	639	881	711
CFE										1,270	1,368	1,119	1,569	1,677
TOTAL										51,667	52,317	53,382	51,547	48,597

Spinning Reserve on Day of Year with Highest State Peak Demand (%)

Control Area	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Day of Non-Coincident Peak Demand	07/22/88	07/20/89	07/13/90	10/02/91	08/17/92	08/02/93	08/15/94	07/27/95	08/14/96	08/06/97	09/01/98	07/12/99	08/16/00	08/07/01
PG&E	7.6	7.2	7.8	5.3	7.0	9.9	6.7	7.4	8.7	6.0	5.7	3.7	1.2	4.7
SCE	8.9	9.3	6.9	10.8	6.4	7.9	7.2	5.0	3.9	5.3	5.6	3.6	1.2	4.6
LADWP	13.8	8.6	14.5	10.7	11.5	13.7	12.1	8.8	4.6	7.8	3.5	6.0	10.5	15.4
SDG&E	8.8	8.2	8.8	6.4	10.4	10.4	6.6	5.1	7.3	5.0	6.1	3.9	1.3	5.0
Statewide	8.9	8.2	8.3	8.3	7.5	9.6	7.5	6.5	6.3	5.9	5.4	3.9	2.2	5.8
SMUD	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CAISO	8.3	8.2	7.5	7.9	7.0	9.1	6.9	6.2	6.5	5.6	5.7	3.7	1.2	4.7
Pasadena										9.0	8.6	8.8	N/A	N/A
IID									N/A	27.0	24.1	32.4	4.9	15.3
CFE										4.6	7.6	13.1	7.1	4.8
TOTAL										6.1	5.8	4.5	2.4	5.9

Spinning reserve is defined as generating capacity which can be brought on line in less than 10 minutes.

Total Reserve on Day of Year with Highest State Peak Demand (%)

Control Area	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Day of Non-Coincident Peak Demand	07/22/88	07/20/89	07/13/90	10/02/91	08/17/92	08/02/93	08/15/94	07/27/95	08/14/96	08/06/97	09/01/98	07/12/99	08/16/00	08/07/01
PG&E	10.9	10.1	8.9	7.8	17.5	16.2	11.4	8.6	5.3	6.5	6.4	4.6	3.4	6.7
SCE	12.2	12.1	10.3	14.2	8.5	11.3	10.2	5.7	8.1	8.7	6.1	4.4	3.3	6.4
LADWP	19.2	10.3	22.4	12.2	23.7	28.5	23.2	8.8	7.0	11.2	8.0	12.3	16.4	20.6
SDG&E	11.9	25.7	18.2	9.4	12.3	24.8	14.2	14.8	9.9	12.2	9.3	6.8	5.0	9.8
Statewide	12.5	11.9	N/A	11.1	14.2	16.2	12.4	7.9	6.9	8.3	6.7	5.5	4.9	8.2
SMUD	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CAISO	11.5	12.1	10.2	10.9	12.9	14.8	11.1	7.8	6.9	7.9	6.5	4.7	3.5	6.8
Pasadena								19.2		37.4	16.4	16.8	N/A	N/A
IID									N/A	35.6	24.1	32.3	17.5	31.1
CFE										15.1	19.4	29.6	7.8	14.9
TOTAL										8.9	7.2	6.4	5.2	8.8

Hour of Day Peak Hit on Day of Year with Highest State Peak Demand (Hours Military Time)

Control Area	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Day of Non-Coincident Peak Demand	07/22/88	07/20/89	07/13/90	10/02/91	08/17/92	08/02/93	08/15/94	07/27/95	08/14/96	08/06/97	09/01/98	07/12/99	08/16/00	08/07/01
PG&E	1600	1600	1500	1600	1600	1600	1700	1700	1600	1700				
SCE	1500	1400	1400	1600	1500	1500	1500	1500	1500	1600				
LADWP	1400	1400	1300	1521	1509	1439	1419	1428	1426	1523	1552	1511	1525	1532
SDG&E	1330	1530	1200	1500	1500	1430	1330	1630	1500	1500				
SMUD	1700	1800	1700	1800	1800	1700	1800	1800	1700	1800	1800	1700	N/A	N/A
CAISO											1626	1652	1517	1616
Pasadena								N/A		1600	1600	1600	N/A	N/A
IID									N/A	1600	1600	1400	1700	1600
CFE										2200	2100	2200	1600	1600

Actual High Temperature on Day of Year with Highest State Peak Demand (Degrees Fahrenheit)

System/Location	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
PG&E-Sacramento	103	103	107	100	101	105	100	102	104	110				
PG&E-San Jose	87	83	87	83	85	97	95	90	84	93				
PG&E-Fresno	106	101	108	91	108	107	106	106	110	106				
SCE-LA & Vicinity	93	90	98	99	99	87	98	95	96	95				
SDG&E-El Cajon	94	94	97	97	102	88	95	95	97	105				
SMUD-Sacramento	103	102	106	100	102	105	103	104	106	107	106	108	N/A	N/A
Sacramento											105	106	98	102
San Francisco											79	87	71	76
San Jose											97	101	86	90
Concord											98	103	94	100
Fresno											104	106	100	103
Los Angeles											105	90	88	85
Ontario											105	103	98	100
San Diego											83	78	78	74
El Cajon											100	98	92	93

2. Given the Recent Cancellations and Delays, and the Uncertainty of the Financial Community, How Many of the Proposed Plants Will Actually Come On Line, and Under What Terms and Conditions?

The Western United States has seen a "gold rush" of sorts over the last few years with over 30,000 MW of proposed projects in California and an additional 75,000 MW in other western states. The capacity of these proposed projects far exceeds demand growth expectations, so it is not unreasonable to see an adjustment in development levels. In such a climate, financial uncertainty is a serious concern for a number of developers and has affected the development prospects for some of the generation projects.

Nevertheless, the Energy Commission believes, based on a review of the individual projects, that 9,781 MW of new generation will come online by 2005, despite numerous cancellations and delays of proposed generation projects. Most of these projects are already under construction and hold power-purchase agreements with the California Department of Water Resources' California Energy Resources Scheduling Division.

New Generation Tracking

The California Energy Commission's Systems Assessments and Facility Siting Division tracks the status of new plant construction and re-powering of existing plants. The projects are assigned to various categories of development. "Planned" projects are those that have been discussed with Energy Commission staff, but have not been publicly disclosed by the developer. "Announced" projects are those that have been publicly disclosed by the developer. Projects that are "In Review" have filed an AFC and are awaiting the Commission's decision regarding the application. "Approved" projects are those that have filed an application for certification (AFC) that has been approved by the Commission.

The Commission continues to track the development of proposed projects to evaluate the short-term outlook of California's supply adequacy situation. The list of proposed projects and dependable capacity is provided in **Table 2-1**. The list of projects is categorized into those facilities that have DWR contracts and others that have a high probability of coming on line.

Table 2-1
California Energy Commission
New Generation Outlook Through 2005

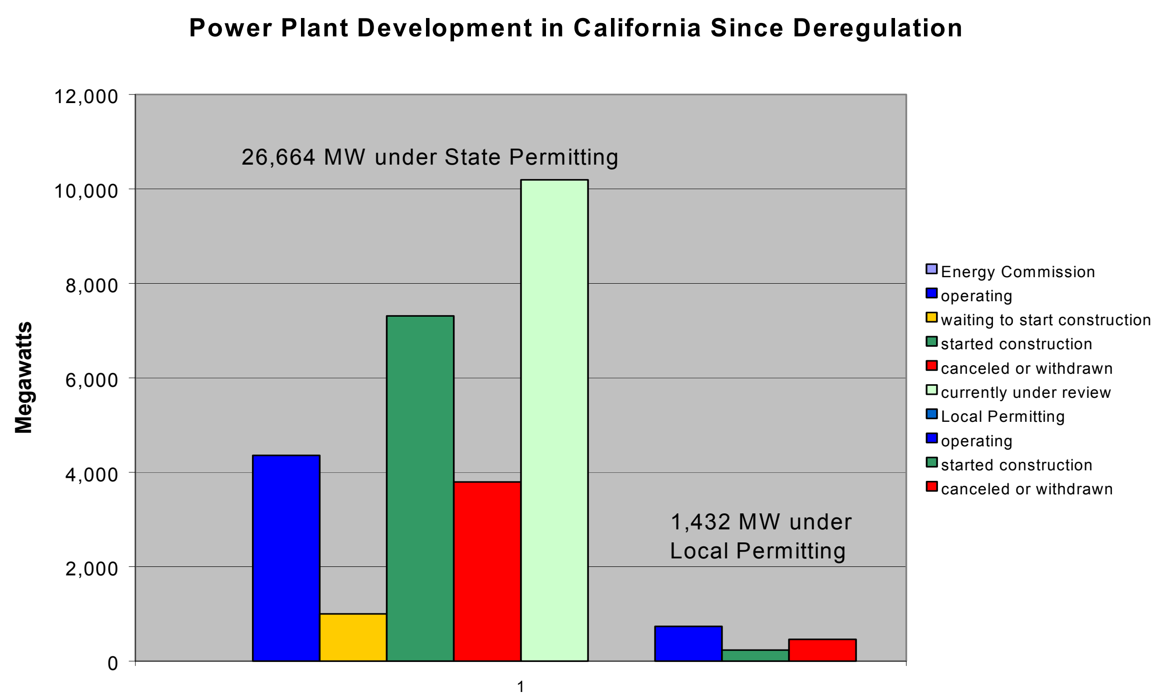
Project	Developer	2003	2004	2005	Expected	Status/Comments
DWR Contract						
Cabazon - Wind	Cab-Partners	12			8/31/02	In construction
Creed	Calpine 3	40			12/30/02	In construction
Elk Hills Phase 1&2	Sempra	480			3/1/03	In construction
Feather River	Calpine 3	40			12/31/02	In construction
Goose Haven	Calpine 3	40			12/31/02	In construction
High Desert	Constellation	796			7/1/03	In construction
Lambie	Calpine 3	40			12/31/02	In construction
Los Esteros Phase 1	Calpine 4	160			12/31/02	In construction
Midway-Lodi	CalPeak	44			6/1/03	Local permitting
Pajaro Valley/Riverview	Calpine 3	40			3/17/03	Local permitting
Sunrise Phase 2	Tex/Mission	265			7/15/03	In construction
Tracy	GWF	150			6/1/03	In construction
Whitewater-Wind	Cab-Partners	18			8/31/02	In construction
Wolfskill	Calpine 3	40			1/15/03	Local permitting
Sempra Contract 2003	Sempra	870			2003	Encumbered Capacity
Los Esteros Phase 2	Calpine 4		70		6/30/04	Announced/ application not filed
Metcalf	Calpine 2		575		5/3/04	In construction
Sempra Contract 2004	Sempra		1420		2004	Encumbered Capacity
Palomar (Citracado)	Sempra			524	1/31/05	CEC Process
East Altamont	Calpine 2			820	3/1/05	CEC process
Otay Mesa	Calpine 2			476	12/31/04	In construction
San Joaquin Valley	Calpine 2			1055	6/1/05	CEC process
Sempra Contract 2005	Sempra			896	2005	Encumbered Capacity
Incremental CEC Additions						
La Paloma	PG&E (NEG)	1005			Fall 2002	In construction
Blythe I	Caithness	499			Spring 2003	In construction
Valero Cogen	Valero	45			9/15/02	In testing
Woodland	MID	77			5/1/03	In construction
El Segundo		6			10/31/02	CEC approved
Coso Navy 2	CA Energy Co.	12			6/1/03	CEC approved
Jackson Valley Biomass		18				
Other/Non-CEC Projects	Various	35				
New Renewables	Various	127				
Pastoria	Calpine		719		Summer 2004	
Malburg	City of Vernon		129		4/30/04	CEC process
New Renewables	Various		212			
Morro Bay	Duke			167	2/1/05	CEC process
East Altamont	Calpine			269	Summer 2005	Available MW after DWR contract
Magnolia	SCPPA			240	3/11/05	CEC process
Cosumnes Phase I	SMUD			480	3/1/05	CEC process
New Renewables	Various			56		
DWR Totals by Year		**3,035**	**2,065**	**3,771**	**5,685**	**Plants with DWR Contracts (minus out-of-state)**
CEC Totals by Year		**1,824**	**1,060**	**1,212**	**4,096**	**CEC Totals by Year**
Combined Yearly Totals		**4,859**	**3,125**	**4,983**	**9,781**	**Combined Yearly Totals**
Total W/out Sempra encumbered capacity		**3,989**	**1,705**	**4,087**		

Changes to List of Proposed Projects

Since 1997, the Energy Commission has received applications for new power plants totaling 26,664 MW. The Energy Commission has approved 12,675 MW of this total. There are 4,361 MW that have been constructed and are now operational, with another 7,314 MW under construction. Approximately 242 MW of projects that received Commission certification have been cancelled, and 3,552 MW have since had their applications withdrawn. The Energy Commission is currently reviewing 10,195 MW of proposed projects that are seeking certification. **Figure 2-1** provides the status of proposed projects since deregulation.

Elsewhere in California during this same time frame, new power plant projects below the Energy Commission's 50 MW jurisdiction filed applications for permitting by local agencies totaling 1,432 MW of which 736 MW are operating, 233 MW are under construction, and 463 MW were canceled.

Figure 2-1

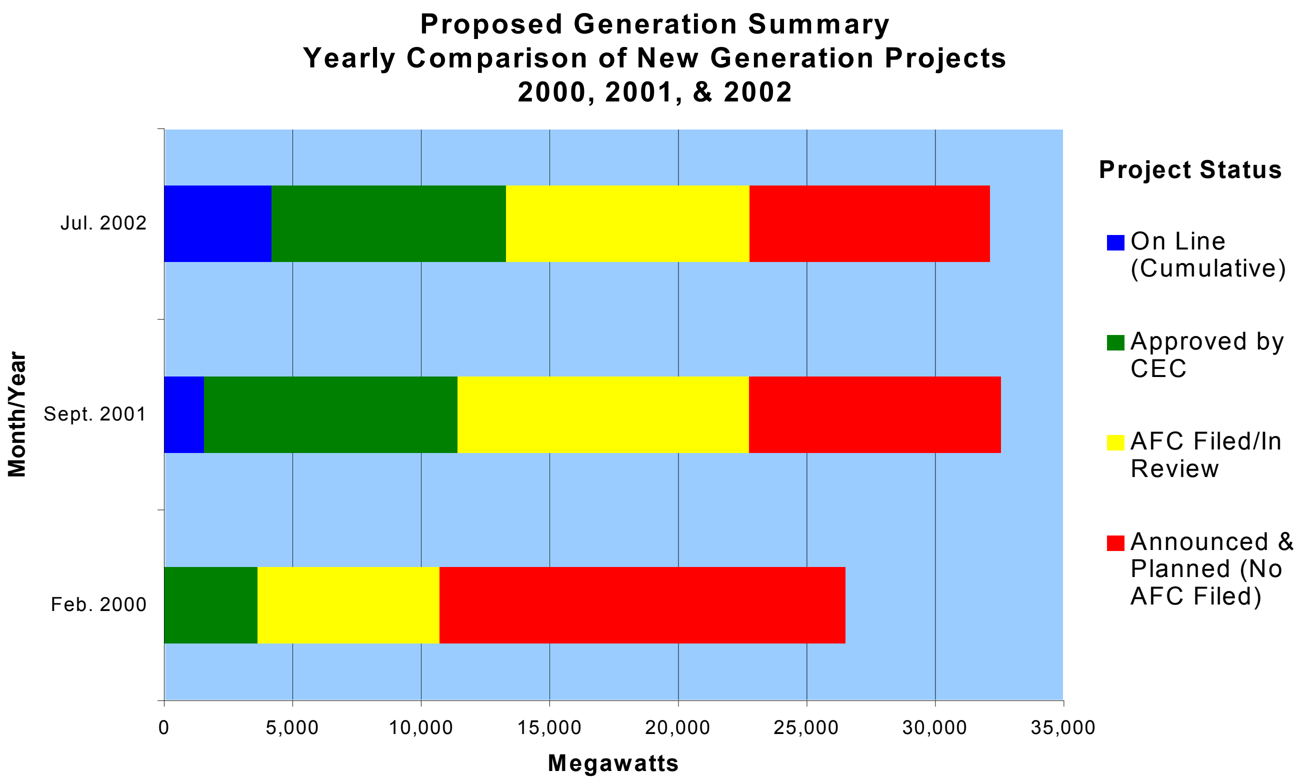


Despite the extensive press coverage on the number of proposed facilities that have been cancelled or postponed, **Figure 2-2** shows that there is still a large number of announced projects. This figure also provides a comparison of the number of facilities that were proposed in 2000, 2001, and in 2002 through July.

Although there have been projects removed from consideration for development, the total number of megawatts the Energy Commission is tracking has been fairly consistent. In

February 2000 the total number of megawatts in all four categories of development (planned, announced, in review, and approved) was 26,500. In September 2001 the number climbed to 31,010 MWs. By August 2002, the number of megawatts totaled 27,920.

Figure 2-2



WECC Proposed Projects

California is not the only western state experiencing problems in getting power plant developers to bring proposed plants on line. Most of the other states within the WECC have had a significant percentage of new plants cancelled and delayed. In 2001 there were a total of 75,710 MW of planned generation throughout the WECC region, excluding California. Of that total, some 20,710 MW (27 percent) have since been cancelled, or delayed one year or more. States with the highest totals of cancellations and delays include Arizona (5,860 MW), Washington (4,806 MW), and Nevada (4,481 MW), for a combined total of 15,147 MW delayed or cancelled.

The regional outlook follows this pattern, as the Southwest and Northwest regions have a combined percentage of 29 percent of projects cancelled or delayed. The Rocky Mountain region has bucked the trend, as 90 percent of the proposed generation are still expected to be built in the next several years.

Despite the delays and cancellations throughout the rest of WECC region (not including Canada or Mexico), there have been 8,942 MW of new generation that has come online recently. The new additions now bring the generation capacity above expected peak demand levels in these regions. There are also 13,916 MW of new generation currently under construction. Much of this additional capacity will likely be available for spot market trades over the next several years.

Boom and Bust

Most analysts believe California and the West have an abundance of generation, even a "glut," following the recent construction boom. This boom-and-bust cycle was correctly identified by Washington State University professor Andrew Ford ("Simulation Scenarios for the Western Electricity Market" Energy Commission Workshop on Alternative Market Structures for California, 11/7/01, Sacramento).

Dr. Ford estimated that demand growth in California averages 2 percent yearly, most of which can be attributed to net population growth (1.9 percent in 2001). California was "under-building" in 1998-2000 at the beginning of deregulation for wholesale markets, followed by massive overbuilding as investors chased after high retail prices for electricity.

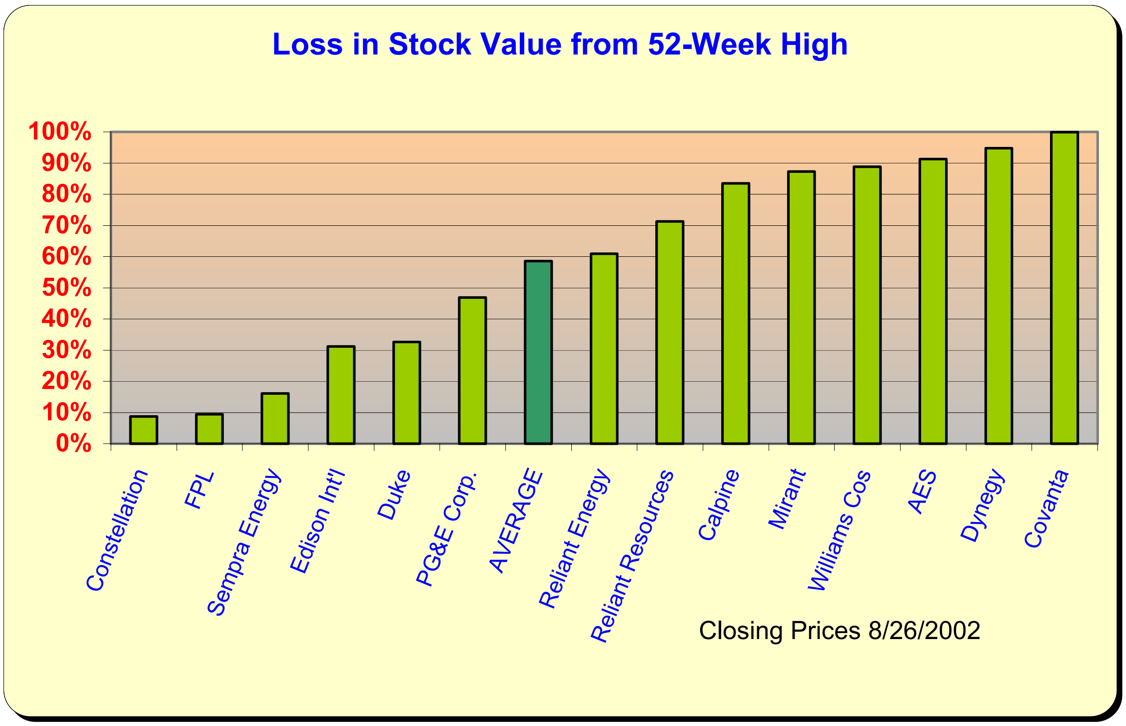
Dr. Ford reported that investors find advantages not to build when reserves exceed 15 percent. They will wait to see prices rise dramatically before starting new construction. Unfortunately, the elapsed time for financing and development increases the risk of outages for end users. These risks are compounded by other uncertainties.

Financial Impacts

The most immediate adverse effects of the slowdown are falling on those corporations that were committed to new plant construction in California. Their employees and shareholders have been hit with job and equity losses. **Figure 2-3** shows the relative decline in equity value for the major companies that were developing plants in California a year ago.

The average stock price decline for these 14 corporations is 58 percent. This is comparable to the 2/3 loss of equity value for US electrical utilities over the past 18 months. This figure is not, however, weighted for the amount of new capacity that was planned. Dynegy and AES lost greater percentages of equity than all other S&P 500 corporations. Covanta filed Chapter 11 bankruptcy in April.

Figure 2-3



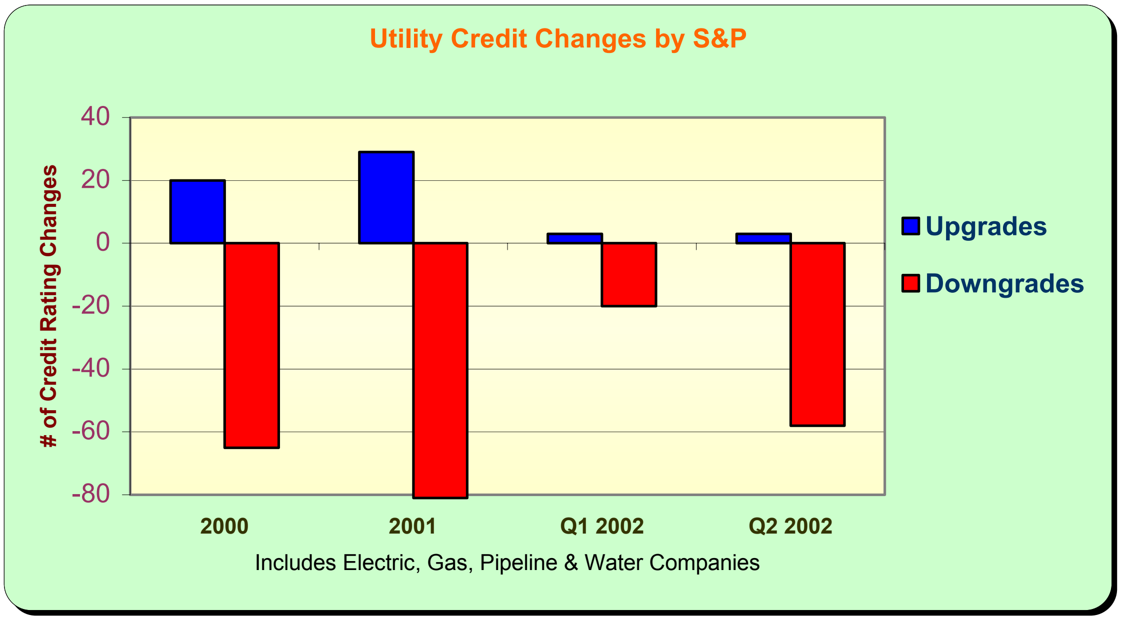
Credit Downgrades

A large majority of electric utility companies and their operating subsidiaries have suffered credit rating downgrades. The trend since Enron's bankruptcy is overwhelmingly negative. **Figure 2-4** shows how this trend accelerated in the second quarter of 2002.

The average rating in the power sector is "BBB", down a notch from "A" last year, but still better than the "BB" average for US industrials. The best ratings among utilities are claimed by water companies, and by the traditional vertically integrated electrical utilities, such as those in the southeast US. At the end of June 2002, just 43 percent of the utility industry had S&P ratings of "A" and above, down from 53 percent a year earlier.

The general credit ratings decrease for power utilities is attributed to their heavy reliance on bank debt, relatively low wholesale electricity prices and postponement or cancellation of planned new power plants. Investors and regulators also have concerns about wash trades (round-trip trades) by companies that may have been using them to meet quarterly revenue expectations. The Securities and Exchange Commission (SEC) has opened inquiries into the accounting or trading arms of Dynegy, Williams, Mirant, and Reliant Energy. Duke Energy has admitted the practice, but says it amounted to less than 1 percent of its trading operations.

Figure 2-4

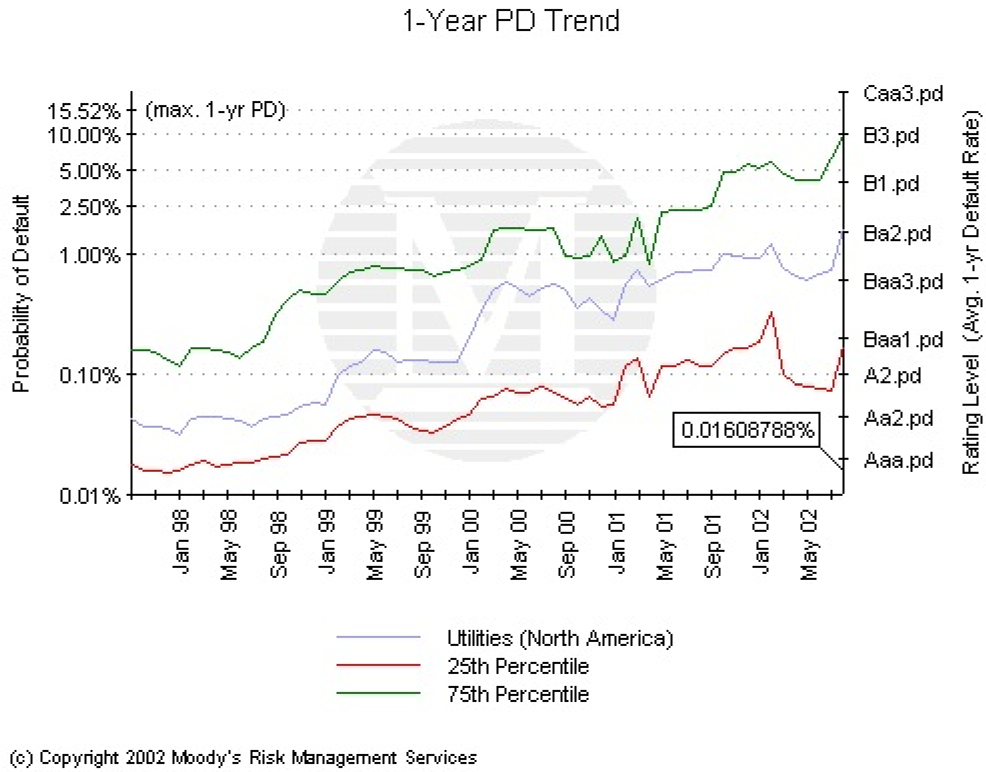


Several plant builders in California have been hard hit by credit rating downgrades. Severely affected companies include Dynegy, AES, Williams, Mirant, and Calpine. These companies have raised large amounts of capital for construction and/or acquisition of plants and pipelines. As their credit ratings fell, some have had large loans (maturities) come due. Lenders are requiring more collateral or liquidity before issuing new loans. Dynegy and Williams have raised collateral and avoided bankruptcy by selling off assets, such as Dynegy's sale of its Northern Natural Gas pipeline. Calpine has canceled or delayed delivery of major equipment, and delayed project development to improve its balance sheet.

By the end of August, several companies had improved their standing on Wall Street. Shares of AES, Reliant Resources, and Williams surged in value as these companies successfully sold assets, reduced debt, raised cash, and renegotiated loans.

The credit downfall of individual electrical utilities is incremental and episodic. However, the negative trend for the industry has been gradual and sustained over the last 60 months, as shown in **Figure 2-5**.

Figure 2-5
Moody's Credit Quality Index for North American Utilities



The middle line is the median for all utilities. This includes water, gas, electric, multi-utilities, and unregulated power companies. This composite rating declined from Aa2 to Ba2. This is associated with a rise in probability of default from 0.08 percent to 1.6 percent. The top line (75th percentile) may be closer to the mean for electric utilities and merchant power corporations. For utilities at the 75th percentile of financial health, average credit ratings have declined from Baa1 to B3. Since 1998, near the beginning of wholesale electricity deregulation in California, the one-year probability of default for this group rose from about 0.12 percent to 9 percent. For utilities and plant builders, this long-term deterioration of credit worthiness will likely increase the cost of capital needed to build new plants.

A Closer Look at California Plant Builders

Table 2-2 provides some general indicators of financial health for large corporations that own or build power plants in California. The list includes Williams Companies, a major trader with DWR contracts, though it does not own or plan to build plants in California. For this group of 13 companies, the average price to earnings ratio is down to 8.9, well below the average of 15.2 for all electric utilities, and 36.9 for the S&P 500. This low ratio is one result of depressed stock values. In the first half of 2002, average revenues were down $1.578 billion, though AES, Calpine, Constellation and Edison posted gains in revenue.

Table 2-2
Energy Company Financial Statistics

STOCK ATTRIBUTES OF CALIFORNIA POWER PLANT DEVELOPERS	STOCK TICKER	STOCK PRICE / EARNINGS (MRQ)	DEBT / EQUITY (MRQ)	PROFIT MARGIN (TTM)	2001 Q1&2 REVENUE $ MILLIONS	2002 Q1&2 REVENUE $ MILLIONS	S&P CREDIT RATING	MOODY'S CREDIT RATING
AES Corp., The	AES	13.2	6.7	3.6%	3,961	4,391	BB-	Ba3
Calpine Corporation	CPN	5.0	3.4	4.9%	2,953	3,680	BBB-	Baa1
Constellation Energy	CEG	24.0	1.2	5.3%	1,957	2,061	BBB+	Baa1
Duke Energy	DUK	12.6	1.5	3.4%	32,071	28,218	A+	A1
Dynegy Inc	DYN	1.7	1.5	0.4%	24,980	18,558	BBB-	B-
Edison International	EIX	1.2	3.7	30.2%	4,642	5,513	CC	B3
FPL Group, Inc.	FPL	15.5	1.1	10.3%	4,107	4,091	AA-	A2
Mirant Corporation	MIR	14.1	1.4	0.5%	16,083	13,407	BBB-	Baa1
PG&E Corporation	PCG	2.2	2.0	10.1%	11,683	10,519	BB+	Ba2
Reliant Energy	REI	4.2	2.3	2.2%	22,369	18,434	BBB+	Baa2
Reliant Resources	RRI	3.1	1.1	1.7%	16,613	15,591	BBB+	Ba3
Sempra Energy	SRE	9.7	1.7	8.3%	5,014	2,954	A-	A2
Williams Companies	WMB	NA	2.6	-1.1%	6,130	4,636	B+	B1
Average		8.9	2.3	6.1%	11,736	10,158	BB	Ba
All Utilities Mean		15.5	1.7				BBB+	
Electric Utilities Mean		15.2	1.8					

MRQ = most recent quarter; TTM = trailing twelve months
Sources: Forbes.com and Yahoo.com, 8/26-27/2002

AES has $2.263 billion in maturities through 2003 and is having severe difficulties finding a source of new credit. AES purchased the 1,056 MW Mountain View project from Thermoecotek, but has halted construction on the Redlands plant after spending over $100 million. AES has completed repowering 225 MW Huntington Beach Unit 3, but has not completed the work it started to repower Unit 4. The company has five plants in Southern California with 4,608 MW total capacity.

Calpine has permitted and constructed the most power plants in California. Total capacity of the company's gas and geothermal plants in Northern California is 2,952 MW. Nationally, Calpine has 24 gas-fired projects under construction, but said it will delay construction on several projects until financial and energy markets are right. Calpine has cancelled and delayed large turbine orders. Outside California, Calpine is also completing a sale/lease of 11 peaker projects (500 MW) to improve its balance sheet.

Caithness Energy of New York buys, builds, and operates geothermal and wind plants in California and Nevada. Caithness, which is privately owned, has partnered with FPL Energy to build Blythe 1 (517 MW), scheduled to go online in April 2003. Blythe 2 (520 MW) is currently in review.

Constellation Energy Group is a merchant energy holding company that includes Baltimore Gas and Electric Company. It is on schedule to complete construction of the 830 MW High Desert project in Victorville, California next July.

Covanta was looking to finance and start construction on the 500 MW Three Mountain gas-fired, combined cycle plant. The project is located next to an existing waste-to-energy plant near Burney, California. Instead, Covanta filed for bankruptcy April 1, 2002. Three Mountain was suspended, along with plans for nine waste-to-energy plants in other states worth $1.2 billion.

Duke Energy has the best credit ratings in the group, but has just announced that it will halt construction of a half-completed 570 MW plant in Deming, New Mexico. Duke also canceled plans to build a 600 MW plant in Clovis, NM after receiving a license August 6. In mid-August, Duke suspended construction on a half-completed $300 million, 650 MW plant near Olympia, Washington. This month, Duke finished major upgrades, improvements, and capacity expansion at 1,026 MW Moss Landing.

Dynegy sold its Northern Natural Gas pipeline to Berkshire Hathaway in mid-August. Dynegy hopes to get $928 million cash, shed $950 million debt, and become a more asset-light company by design instead of default. Dynegy's only California project in permitting is the repowering of El Segundo. The company lost $328 million in Q2. Some analysts believe the sale of pipelines by Dynegy and Williams will further impair their ability to earn a profit. Dynegy owns 1,271 MW capacity from eight plants, all in San Diego County. In partnership with NRG, Dynegy has an ownership interest in four other South Coast and San Joaquin Valley plants that total 1,716 MW.

Edison International earned $182 million in Q2. Low wholesale power costs have boosted Southern California Edison's credit rating to "BB", up from "D" last year. These same prices have hurt plant-building subsidiary Edison Mission Energy, recently downgraded to "BBB-". Edison Mission Energy, in partnership with Texaco, has completed the 320 MW simple cycle Sunrise project, and is now constructing the 256 MW combined cycle phase of the same project.

Enron secured permits for two projects that were then sold to Calpine: 555 MW Los Medanos (completed July 2001), and 750 MW Pastoria (suspended). Now in bankruptcy, Enron has suspended permitting of the 900 MW Roseville project while it is looking for a buyer.

FPL Group is still in good financial health, but on August 19 canceled efforts to certify a 560 MW plant in Rio Linda near Sacramento. The company blamed the application process for delays; especially air pollution offset requirements and local opposition. Market conditions and economic assessments are believed to be more fundamental. FPL's 1,120 MW Tesla plant near Tracy, California is in review. A subsidiary, FPL Energy, operates 566 MW in California, mostly wind and solar projects, and two 49 MW plants in Bakersfield.

Mirant stated August 14 that it might have inflated revenues in 2001 by as much as $1.1 billion. Mirant lost $151 million in Q2, and has sold $1.6 billion in assets. Planned capital expenditures have been cut. Mirant has stopped construction on the 500 MW Contra Costa project. Mirant does have 2,740 MW capacity in the San Francisco Bay Area, from three plants purchased from PG&E.

PG&E Corp saw the credit rating of its plant-building subsidiary, National Energy Group (NEG), lowered to "junk" status August 12. This forced negotiations with lenders for $1.6 billion in credit agreements. NEG is completing construction on the 1,048 MW La Paloma plant near McKittrick in western Kern County. PG&E sold its 580 MW Otay Mesa project to Calpine. PG&E retains ownership of 3,139 MW in thermal generation, mostly from 2,160 MW Diablo Canyon.

Sempra is maintaining its investment grade. Sempra is building a 600 MW plant in Mexicali, and plans to develop the 500 MW Palomar plant in Escondido. The 500 MW Elk Hills plant, a joint project with Oxy near Bakersfield, is scheduled to begin operations next spring. Contracts to deliver up to 1,900 MW to the State of California for up to 10 years are currently under re-negotiation.

Reliant Resources had its credit ratings lowered in July. Moody's rates it "junk", but S&P still considers it investment grade. With $1.2 billion in cash, and $6.7 billion in outstanding debt, the company had to post additional liquidity of about $600 million. It is 80 percent owned by its parent corporation, Reliant Energy (REI), which in July revised its reported revenues down $7.9 billion (8.7 percent) due to electric and gas wash trades over the last three years. Reliant withdrew its application for the 800 MW Colusa project, and does not have any other projects in permitting or construction. Reliant has 3,834 MW in Southern California from five plants acquired from Edison in 1998.

Williams Companies lost $498 million in Q2, and was close to bankruptcy in mid-August. Williams does not own any plants in California. Though it has significant energy delivery contracts with DWR, Williams is not building or seeking permits for new generation. The SEC is investigating both wash trades and trading reserves involving Williams. To replenish liquidity, it has sold $1.5 billion in pipelines and natural gas production properties in the last five weeks. Other assets have been posted as security for $2 billion in new credit lines. The company has $15 billion in long-term debt, including $1.8 billion due later this year.

3. What Will the Lingering Effects of Behavioral Conservation Be, and What are the Permanent Effects?

Californians reduced their electricity demand in 2001 primarily through two forms of response. Consumers either conserved through behavior change (e.g., turning up the thermostat to reduce air conditioning use or changing operating schedules), or invested in more efficient equipment (e.g., replacing an older central air conditioning unit with a high efficiency unit).

The kinds of conservation strategies that consumers pursue significantly affect the persistence of these demand reductions into the future. For example, investments in high-efficiency equipment will generally reduce energy consumption and peak demand over the useful life of those investments. Likewise, demand-management technologies, such as energy-management control systems and advanced interval meters equipped with two-way communications, will enable customers to shift loads in response to prices well into the future. Behavioral or operational changes, however, are less likely to persist over time without efforts to sustain them.

The Energy Commission believes it is reasonable to assume that no more than about half of the aggregate peak demand reductions observed in 2001 will persist for many years. Based on recent studies by Lawrence Berkeley National Laboratory (LBNL) and the Energy Commission's own analysis of energy consumption patterns, it appears that 25-30 percent of the customer load reductions observed in 2001 were the result of energy efficiency investment and on-site generation gains. Behavior changes contributed the other 70-75 percent of the observed load reductions in 2001. Follow-on research in 2002-03 will further refine these estimates and analyze their proportional contributions to future load reductions.

Demand Reduction in 2001 and 2002

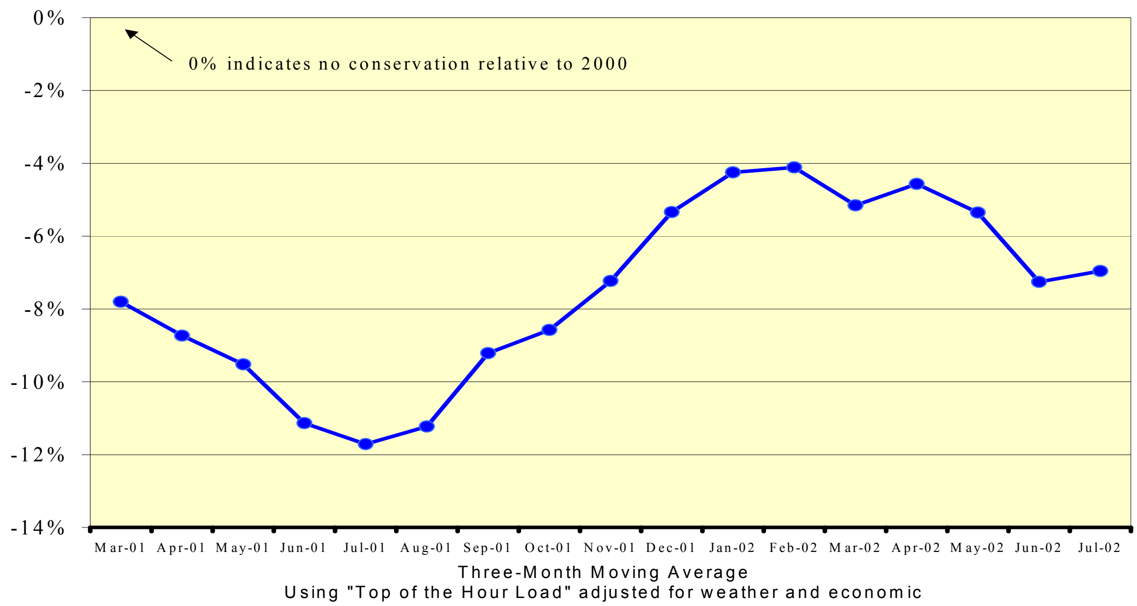
Californians responded to the uncertain energy conditions and conservation requests from the governor and other public officials with unprecedented efforts to reduce peak demand. Peak electricity demand in 2001 was lower than 2000 for every month, even adjusted for weather and economic conditions. The peak savings amounted to between 2,000 –5,600 MW per month compared to 2000[1]. This reduction is a result of several factors, including:

- A landmark energy efficiency and demand reduction program that may represent the largest conservation effort ever launched by a single state,
- Electricity price increases,
- The 20/20 program,
- Voluntary conservation, and
- Response to winter rotating outages and media coverage of the crisis.

[1] See "Actual Data Jan.-Dec. 2001" at WWW.energy.ca.gov/electricity/peak_demand/2001_peak_demand.html)

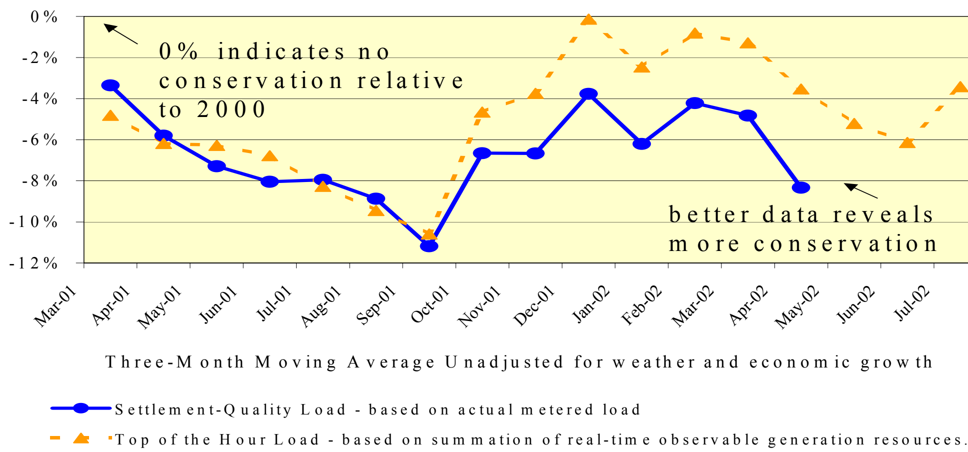
Monthly peak demand for 2001 relative to monthly peak demand in 2000 is shown in **Figure 3-1**. In 2001, the three-month moving average reached almost –12 percent, indicating that demand was 12 percent lower than would be expected after adjusting for weather and economic growth. Since last summer, the three-month average of estimated voluntary conservation has declined but has persisted at between –4 percent and –8 percent -- roughly half that achieved in the summer of 2001. For the last three months, average adjusted monthly peak demand is about 7 percent below the 2000 monthly peak demand.

Figure 3-1
Monthly ISO Peak Demand as Percent of 2000 Monthly Peak



The Energy Commission developed these estimates using the "Top of the Hour Load" posted continuously by the California ISO, as a way to quickly estimate the persistence of overall voluntary and program conservation behavior. However, these are raw data that measure only those generation resources observable to the ISO at any given moment, and provide only a snapshot of demand trends. The ISO has also provided the Energy Commission with "settlement quality" data for hourly demand through April of 2002. The settlement data are based on actual metered load and are quality-controlled. These data indicate similar levels of conservation for the summer of 2001, but suggest that for 2002 the "Top of the Hour" data may be leading to overestimates of load growth and underestimates of conservation. **Figure 3-2** shows monthly peak demand (unadjusted for weather or economic growth) as a percent of 2000. For the last three months for which both series are available, "Top of the Hour" peak demand is averaging 3.5 percent less than 2000, compared to 8 percent less indicated by the settlement-quality data. Therefore, **Figure 3-1** most likely portrays a conservative estimate of persistence.

Figure 3-2
Monthly ISO Peak Demand as Percent of 2000 Monthly Peak



Demand Reduction Response Strategies: Behavior and Investments

Californians reduced their electricity demand in 2001 through two categories of response,

- Conservation behavior (e.g., turning up the thermostat to reduce air conditioning use), and
- Investment in efficient equipment (e.g., replacing an older central air conditioning unit with a high-efficiency unit).

Conservation behavior includes activities such as changing when or how certain energy-using equipment is operated. The range of actions would encompass using energy-intensive equipment less often, discarding unnecessary appliances, turning off equipment when not in use, using less energy-intensive equipment (e.g., fans instead of AC), postponing equipment use to off-peak times, and other variations in operational practices. The *Flex Your Power* mass media campaign specifically targeted many of these kinds of behavioral activities. Doing without the use of a particular appliance for some period of time is another possible form of conservation behavior.

Investments in energy-efficient hardware may involve replacing existing equipment with higher efficiency models or selecting an energy-efficient model when making a new equipment purchase. Utility and other state energy efficiency programs focused especially on stimulating investments that lower both overall energy use and peak demand. Unprecedented levels of vendor and retailer participation strengthened these programs.

The two strategies have important implications for gauging the continued reduction in the demand for electricity in California. Some data is available to estimate the relative size of each of these strategies among residential and commercial/institutional consumers.

Recognizing that the energy situation of 2000-2001 presented a unique opportunity to gather information about conservation decision-making and practices, the California Energy Commission funded a detailed evaluation of consumer response during the summer of 2001 and beyond. That research, conducted by Dr. Loren Lutzenhiser and Washington State University (WSU study), focuses on the actions of residential, business, government and agricultural consumers. Residential data consists of 1,860 telephone interviews with randomly selected electricity customers across the state's five major utility service territories, and records of monthly household electricity consumption for 1999-2001. Additionally, each utility supplied a random sample of 5,000 household billing files covering the same years for comparison.[2]

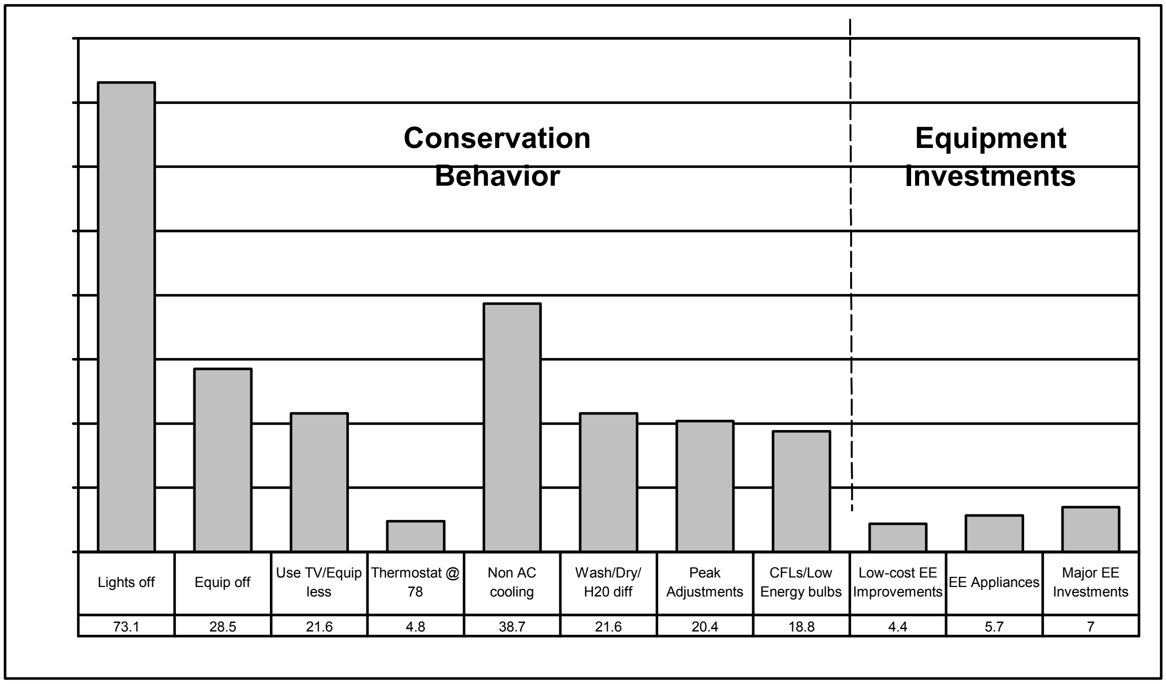
Residential Demand Reduction Response

A vast majority of residential customers surveyed reported concerns about the energy situation and expressed a willingness to actively reduce their own consumption. About 79 percent of California households reported making changes in their energy use in response to the crisis. This group will be referred to as the "conservers." Of the 21 percent who reported making no behavior changes, most (66 percent) believed their energy use was already low. Only 14 percent reported that they were either unaware of how to make changes to reduce energy use or did not see any reason to change.

The survey respondents who reported making changes in their energy-using behavior identified an average of 2.4 actions. Respondents were asked to describe their actions in their own words rather than picking actions from a pre-selected list of actions. (This style of questioning reduces over-reporting bias and provides a more robust data set.) The answers were grouped into eleven categories and are shown in **Figure 3-3**.

[2] For a fuller discussion of these findings, see Lutzenhiser, Loren. (2002) *An Exploratory Analysis of Residential Electricity Conservation Using Survey and Billing Data: Southern California Edison, Summer 2001*, California Energy Commission Publication 400-02-006F and Lutzenhiser, Loren, Gossard Marcia Hill, and Sylvia Bender (2002) "Crisis in Paradise: Understanding the Household Conservation Response to California's 2001 Energy Crisis." Proceedings of the American Council for an Energy Efficient Economy Summer Study, Volume 8.

Figure 3-3
Demand Reduction Actions Taken by California Households



Category	Description
Lights off	Turn off lights or use fewer lights
Equip off	Turn off equipment when not in use (including less pool & hot tub use)
Use TV less	Turn off television or watch less television
Thermostat @ 78	Raise air conditioner thermostat setting to 78 degrees or above
Non-AC Cooling	Use the air conditioner less often or not at all
Wash/Dry less	Wash clothes or dishes less frequently, use a clothesline instead of dryer
Peak Adjusts	Use less energy during peak hours and/or shift specific energy uses to off-peak hours
CFL/bulbs	Install compact florescent bulbs or other energy saving/low-watt bulbs
Low-Cost EE	Make low cost investments (purchase fans, plant trees, add awnings, service air conditioner, purchase evaporative cooler, add timers or motion detectors)
EE Appliances	Purchase energy-efficient appliances
Major EE	Make major efficiency investments (whole house fan, solar panels, add insulation, purchase new or energy-efficient air conditioner)

The actions shown in **Figure 3-3** range from fairly common (e.g., turning off lights reported by 73 percent of the conserver households) to relatively rare (e.g., making low-cost efficiency improvements reported by 4.4 percent of the conserver households). Setting thermostats at 78 degrees or higher, a behavior targeted by the conservation media campaign, was reported in only about 4 percent of the households (or 7 percent of conserver households having central air conditioning). However, nearly 40 percent of households either chose not to use air conditioning at all, or to use it more sparingly.

Next in frequency came altering washing or drying patterns, shifting energy use to off-peak hours, and installing compact fluorescent lamps (CFL) or other "low energy" bulbs, each reported by about 20 percent of the conservers. As many as 8 million CFLs may have been rebated or given away, which increased their market share to 8 percent of lighting. Since CFLs may easily be reversed to less efficient incandescent lighting, they are not counted as "equipment investments."

Finally, four to seven percent of households reported making energy efficiency investments in each category. These investments included buying ENERGY STAR™ appliances, and installing new ceiling fans, windows, insulation, or solar systems. Taken together, equipment investments total approximately 17 percent of the conservation actions reported by households that took some action to reduce consumption.

Motivations for Actions and Sources of Influence Among Residential Households

Households were motivated to reduce peak demand and overall energy consumption for a variety of reasons. Their decisions were similarly influenced by multiple sources of information. A summary of consumer motivations for taking action is presented in **Table 3-1**.

Table 3-1
Motivations for Conserving Energy (Percentages)

	Very Important	Somewhat Important	Unimportant
To keep electricity bills down	76.5	20.4	3.1
To qualify for a utility rebate	33.4	34.9	31.7
To do your part to help Californians through a difficult time	69.1	23.6	7.3
To try to avoid blackouts	76.8	15.8	7.4
To use energy resources wisely as possible	77.9	18.8	3.3
To protect the environment	70.4	21.0	8.6
To stop energy suppliers from overcharging	78.8	12.8	8.4

Among those who changed their energy use in response to the crisis, five motivations were considered *very important*. These were: "keeping electricity bills down" (76 percent), "doing your part to help ..." (69 percent), "trying to avoid blackouts" (77 percent), "using energy resources wisely" (78 percent), and "to stop energy suppliers from overcharging" (79 percent). These responses indicate a mixture of economic self-interest, civic and altruistic motives, as well as widespread agreement with the notion that exploitative energy pricing was a key cause of the crisis. Concern for environmental protection was also reported to be "very important," by a large majority (70 percent). "Qualifying for a utility rebate" was seen as very important to approximately one-third (33.4 percent) of those surveyed.

Once the conserver is concerned and motivated, action depends on having knowledge of what to do and how to do it and the ability to carry out the action. Analysis of the various sources of influence indicates that they vary in their effects upon consumers' conservation choices and actions. **Table 3-2** reports these results.

Table 3-2
Sources of Influence on Energy Conservation Decisions and Actions (Percentages)

	Major Influence	Minor Influence	No Influence	Never Use This
Information included in utility bill	21.1	44.9	33.1	0.9
Suggestions by friends or neighbors	10.7	37.6	50.4	1.4
Things suggested by co-workers	9.7	30.1	51.4	8.8
News stories on television	44.1	34.5	20.4	1.0
Advertisements on television	30.9	37.8	30.0	1.3
Information from the radio	24.3	37.4	35.4	2.9
Information from world-wide web	9.7	27.7	54.0	8.6
Education programs from a school	14.2	19.1	59.4	7.3
Information from community groups	11.8	24.3	59.2	4.7
Product rebates related to conservation	20.7	35.5	41.4	2.4
Recommendations of building contractors	11.5	20.0	63.2	5.3
Past experience or common sense	83.3	13.2	3.4	0.1

News stories on television are seen by a large minority of consumers (44 percent) to be a "major influence." Social networks, which have been identified as important sources of influence on conservation behavior in previous research, seem much less influential. About half of the respondents said that their friends, neighbors and coworkers had had "no influence" on their conservation actions/choices.

Education programs at school and information from community groups were also reported to be less influential than other sources, although 35 percent of the sample did say that these sources had some influence. The lack of significant influence of websites in this sample is also notable. Only 10 percent said that Internet sources were a "major influence," and 63 percent said that the web either had "no influence" or was "never used." Finally, more than 80 percent of the respondents saw "common sense" and "their own past experience" as major influences. This suggests that many conservation alternatives are seen as obvious things that one *could* do, but may choose for one reason or another not to.

A host of factors influence the ability of consumers to plan and implement energy conservation actions. Different consumers are constrained by such things as the availability of products in the market, access to financing, the realities of how their dwellings are designed, constructed, and oriented. When survey respondents were asked if they planned further conservation actions, about 48 percent said that they would like to make specific efficiency investments. But when asked about impediments to action, the overwhelming majority also volunteered that "price," "cost," "lack of money," or "financial considerations" were limiting factors.

About 15 percent of the household survey respondents indicated that their conservation actions had actually "improved [their] quality of life" and 58 percent said that their conservation had "had no serious effects" on quality of life. Over 60 percent of the respondents believed that "real changes must be made" in lifestyle in order for California's energy problems to be solved.

The Relationship between Weather and Residential Behavior Change in 2001

Some analysts have suggested that cooler-than-average temperatures in 2001 are responsible for the reduced demand levels. It appears that households used less electricity in response to heating and cooling degree days after September 2000. This conclusion is based on regression analysis, using electricity bills for residents living in the same house for 1999-2001, and summary weather statistics for each bill. Additionally, the analysis revealed that this change in behavior was concentrated in a few households. This change did not occur evenly across the entire population in much of the state. The notable exception to this skewed pattern is in the service area of Los Angeles Department of Water and Power (LADWP). The data indicates a much more uniform response to weather across the customer base in LADWP territory than in other areas of the state.

The magnitude and duration of such concentrations of response is not yet fully understood. A random sample was studied involving 5,000 Southern California Edison (SCE) accounts for June 2001. Preliminary investigation suggests that 30 percent of the households may have been responsible for the 75 percent of the utility's total kWh reduction that month. It is apparently not the case that high levels of concern, commitment, exposure to information, and actual efforts to conserve are sufficient to produce a significant conservation effect in the majority of the population. Further analysis is underway, including of additional months of data from SCE, and new data from Pacific Gas & Electric Co., San Diego Gas & Electric Co., Sacramento Municipal Utility District, and LADWP. It will be important to characterize this group of conservers more fully for program planning purposes.

Commercial and Institutional Demand Reduction Responses and Motivations

Researchers at Washington State University (WSU) conducted 84 semi-structured interviews with members of commercial and institutional organizations. Many of these organizations participated in state or utility peak load reduction programs. WSU also interviewed 21 key individuals who work as program managers, administrators, aggregators, energy service providers, and utility representatives.

While there were savings in this sector (as measured at the system level), conservation action by firms and public sector organizations was not universal. The nature of the actions taken and their potential effectiveness varied, even across organizations that appeared to be relatively similar in important ways[3].

- Rising energy prices impacted organizations in different ways. For public sector organizations, the impact of higher prices on budgets was a significant concern

3 For a fuller discussion of the commercial/institutional response, see Lutzenhiser, Loren, Kathryn Janda, Rick Kunkle, and Christopher Payne (2002). Understanding the Response of Commercial and Institutional Organizations to the California Energy Crisis. Report prepared for the California Energy Commission.

because these organizations have fixed incomes and strict budgetary requirements. Private firms were more concerned about remaining profitable. Some firms can pass higher energy costs on to their customers, while others may have to absorb them. Some organizations were affected very little by higher energy prices. These included: small organizations with little energy consumption, organizations served by municipal utilities, and organizations with fixed price contracts with third-party suppliers.

- Public opinion influenced government and retail organizations to take visible conservation actions such as reducing lighting levels to demonstrate they were doing their part.
- For local governments, blackout threats posed significant health and safety concerns for their jurisdictions. Private firms were concerned about loss of business and security issues.

Organizational responses to the energy crisis depended upon their particular circumstances and their ability to act within the limited time frame of the crisis.

- Some organizations responded quickly to the energy crisis to address budget concerns and public expectations. This often led to operational type actions such as changes to thermostat settings and operating schedules, turning off lights and equipment, and other conservation activities that could be implemented quickly. However, contractual constraints with tenants and/or operational requirements limited opportunities for many private sector firms.
- When making decisions about actions involving efficiency improvements to their buildings, organizations considered things they were already planning to do, recognized problems that needed to be addressed (repairs/replacement of failing equipment), and what was judged to be possible. Firms that had been making efficiency improvements in their facilities for many years were less able to respond to the crisis any further.
- Technology, such as an energy management system, made it easier for some organizations to take action to control or limit their energy use. Planning for action was also easier for those organizations with building stocks of similar buildings (e.g., chains or big box retail). Organizations with large and diverse building stocks required a higher level of effort to produce comparable levels of savings.
- The energy crisis got the attention of key decision-makers in many public and private organizations. Attention from the top levels of the organization is often an important determinant of how seriously actions are pursued. Whether energy decisions are made at the national or local level can impact the ability to take action in both positive and negative ways.
- Organizations drew upon past experience and institutional knowledge to respond to the 2001 energy situation. Many of the local governments and office building management firms had some past experience with energy efficiency investments or conservation efforts. Their experience and knowledge allowed some organizations to respond more quickly to programs.
- Both public and private organizations used peers/trade allies (including watching competitors) and peer organizations as sources of information and models for action.

For the desired energy behavior to continue, a shift from a short-term crisis mentality to a long-term policy approach is needed. This will be discussed in the next section.

How Much of the 2001 Response is Likely to Continue?

Consumer demand for household energy is considered relatively inelastic. Behavior change is seen as rare and resisted; post-conservation "snap-back" is expected. This view reinforces twenty years of generally modest support for household energy conservation/ efficiency programs in the U.S. In California during 2001, all of this changed. Large-scale mass media energy information campaigns accompanied by financial incentives were directed to all customers. Consumers also experienced price increases and threats of rotating outages. There was widespread media coverage of the political and economic turmoil surrounding the energy supply system.

Californians responded with a dramatic reduction in electricity demand. Individuals and businesses conserved on their electricity usage both on peak and overall. Consumers increased their attention to managing energy use. Ratepayers invested in high-efficiency equipment and appliances, onsite generation, and demand-responsive technologies. Nearly all of the WSU survey residential respondents stated late in 2001 that they would continue with the energy-reducing actions they reported "*…if the energy situation stays the same as it is today.*"

In August 2002, however, the energy situation is not the same. Fifteen months have passed since the last rolling outage. Power supplies and utility bills have stabilized. The public awareness campaign is airing its conservation advertisements at reduced levels compared to 2001. Media coverage focuses on legal and financial troubles of embattled out-of-state energy producers rather than conservation issues. State forecasts indicate that Californians should have adequate supplies of electricity, even with warmer than normal temperatures, as long as consumers continue to use energy efficiently.

Residential Persistence

During the summer in California, the dominant source of residential electricity load in summer in California is air conditioning. Changes in the use of air conditioning are largely responsible for the dramatic declines in summer demand seen in 2001. Despite messages directing consumers to set programmable thermostats to higher temperatures, a majority of consumers chose instead to use the air conditioner less often or not at all. These choices may represent new habits (or rediscovered ones) for some consumers.

Once a new pattern of behavior is adopted, repeated successful use is self-reinforcing. In 2001 this self-reinforcement was helped by intensive media coverage, frequent advertising messages asking every one to do their part to get through a crisis, and, possibly, a 20 percent reduction in a bill through the 20/20 program, or, at least, avoiding a rate increase by staying within 130 percent of baseline usage. Once the success pattern is broken, however, rapid return to the previous pattern is possible. Lack of a "crisis" atmosphere, a change in household composition or characteristics (e.g., a new baby or a remodeling project) which increases the bill, and a period of hot weather could push a portion of non-AC users back into being regular AC-users.

With further analysis of the survey, weather, and billing data, and new follow-up surveys with the same households in September 2002, we hope to shed more light on what people can and will actually do in real world conditions. The coming phase of the research will focus more thoroughly on why some persons conserved at such high levels and with such significant effects, and its flip-side, why the conservation actions were not more widespread in the residential sector.

Commercial and Institutional Persistence

The commercial and institutional interview respondents generally held a favorable view of the results of their actions. Many believe they had reduced their electricity demand, and that this contributed to the lack of blackouts. Employees responded positively to changes and customers expressed few complaints. The respondents felt that their actions helped to mitigate the negative effects of the energy crisis on their organizations.

Many acknowledged, however, that they did not yet have the data to show they had actually saved energy. In some cases, organizations were still implementing or had just completed efficiency investment projects. The full savings impacts from these projects will not be evident for some time. Although it is clear that time is needed for organizations to fully judge the effects of their actions and whether this experience supports continuation of those efforts, our respondents generally felt their conservation efforts and efficiency investments would continue. New organizational policies and procedures, and newly identified efficiency opportunities are now reinforced by higher (and still uncertain) prices. This seems likely to produce additional voluntary savings in the future. To the degree that organizational structures were changed to accommodate new input on energy management and consumption, results may be more lasting.

The energy crisis raised the level of concern for energy use by organizations. However, the respondents voiced three factors they believed could erode the level of concern that occurred in 2001.

- Media attention devoted to the energy crisis has largely disappeared. The current coverage of the energy industry and its major players is producing mixed messages about the crisis and the need for continued conservation.
- Security issues and the economic recession are taking over the attention and resources of organizations. Energy is pushed to a lower priority.
- Some of the peak reduction programs that promoted peak reduction have disappeared. The current state financial situation makes it difficult to justify continued appropriation levels for these programs.

The policy question becomes how to support commercial/institutional concern about energy, provide opportunities for conservation and efficiency, and improve commercial/institutional ability to act on opportunities. Based on this research, programs and policies will need to:

- Use existing peer networks and service delivery mechanisms to develop relationships with organizations and to better understand how they operate.
- Create more certainty in the marketplace. Programs and policies need time before they are incorporated into organizational processes.
- Reward, encourage, and support good long-term energy management practices in organizations.
- Support organization efforts to be more responsive consumers of energy.

4. What Impact Will the Significant Rate Increases Have on Load and Consumption Patterns?

Isolating the effects of price on demand from those associated with responses to fear of rotating outages, public calls for conservation, efficiency programs, bill incentives, and other influences is a significant challenge given the nature of the crisis. However, the Energy Commission currently has studies underway that it hopes will help to sort out these influences.

Nevertheless, the Energy Commission believes that consumers should have the opportunity to respond to prices, and that, if they did, significant demand response would occur. In this regard, many consumers already have interval meters installed on their premises. Once the CPUC completes its demand-responsive, rate-design proceeding, those consumers will have the tools to respond to varying prices.

The Energy Commission is committed to continued enhancement of consumer demand-responsiveness capabilities. In this regard, the Energy Commission, the CPUC, and the Power Authority are working jointly to implement dynamic pricing tariffs and programs.

Tariff Changes for Customers of Investor-Owned Utilities[4]

Three price changes were introduced into the California retail electricity market during 2001. First, AB 1x instituted a one-cent per kilowatt-hour surcharge on all electricity customers. Second, the CPUC authorized an additional three-cent per kilowatt-hour average rate increase beginning June 1, 2001. That allocation method included exemptions from the increase for certain low-income customers and all residential usage below 130 percent of baseline, block pricing increases for residential customers with very high usage, and substantially higher on-peak rates for industrial time-of-use (TOU) customers. Third, starting in June, 2002, all customers with demand greater than 200 kW were required to shift to a TOU tariff (if they were not already on such a tariff) after receiving real-time electric meters and remote communication systems mandated by AB29x.

Tariff Changes for Customers of Municipal Utilities

The Energy Commission has information for five municipal utilities: Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), the City of Burbank Water and Power Department (Burbank), the City of Glendale Water and Power Department (Glendale), and Pasadena Water and Power (Pasadena). LADWP has frozen its rates and has announced a possible 10 percent

[4] Greater detail on historic and future rates may be found on the Energy Commission website at: http://www.energy.ca.gov/electricity/current_electricity_rates.html.

decrease in rates for customers in 2002 and 2003. SMUD, on the other hand, implemented an average 18 percent rate increase in May of this year. SMUD's 10-year resource plan released on October 4, 2001 details two 1/4 cent rate increases that were instituted in May 2001, but scheduled to be dropped in 2002 and 2004. SMUD decreased its rates by 1/4 cent on May 1, 2002 as planned. The other municipal utilities have been adjusting their rates to reflect the energy fuel cost, but have mitigated some of the impact with their rate stabilization funds that have been accumulating since 1997. The City of Burbank Water and Power utility may incur additional increases taking effect in July of 2003. Glendale Water and Power has added new tiers to its tariff schedules to reward electricity conservation and penalize excessive use of electricity.

Price Forecasts for Municipal and Investor-Owned Utilities

The tariff changes described above resulted in the rate increases ranging from a penny or less for municipal utility customers, and between 1.6 cents – 5.7 cents/kWh for their IOU counterparts. (See **Table 4-1**.) The overall impacts are shown in **Figure 4-1**. We anticipate that the highest rates will begin to decline in 2004, and rates should return to their previous trajectory by 2010 as the DWR contracts and remaining debt are paid off.

Table 4-1

Average IOU Electricity Prices
¢/kWh Nominal

	Residential	Small Commercial	Medium Commercial	Industrial
2000	11.5	11.9	10.1	7.9
2002	13.1	17.6	14.3	11.2
2005	12.5	15.3	12.0	8.9
2010	11.7	14.9	11.7	8.4

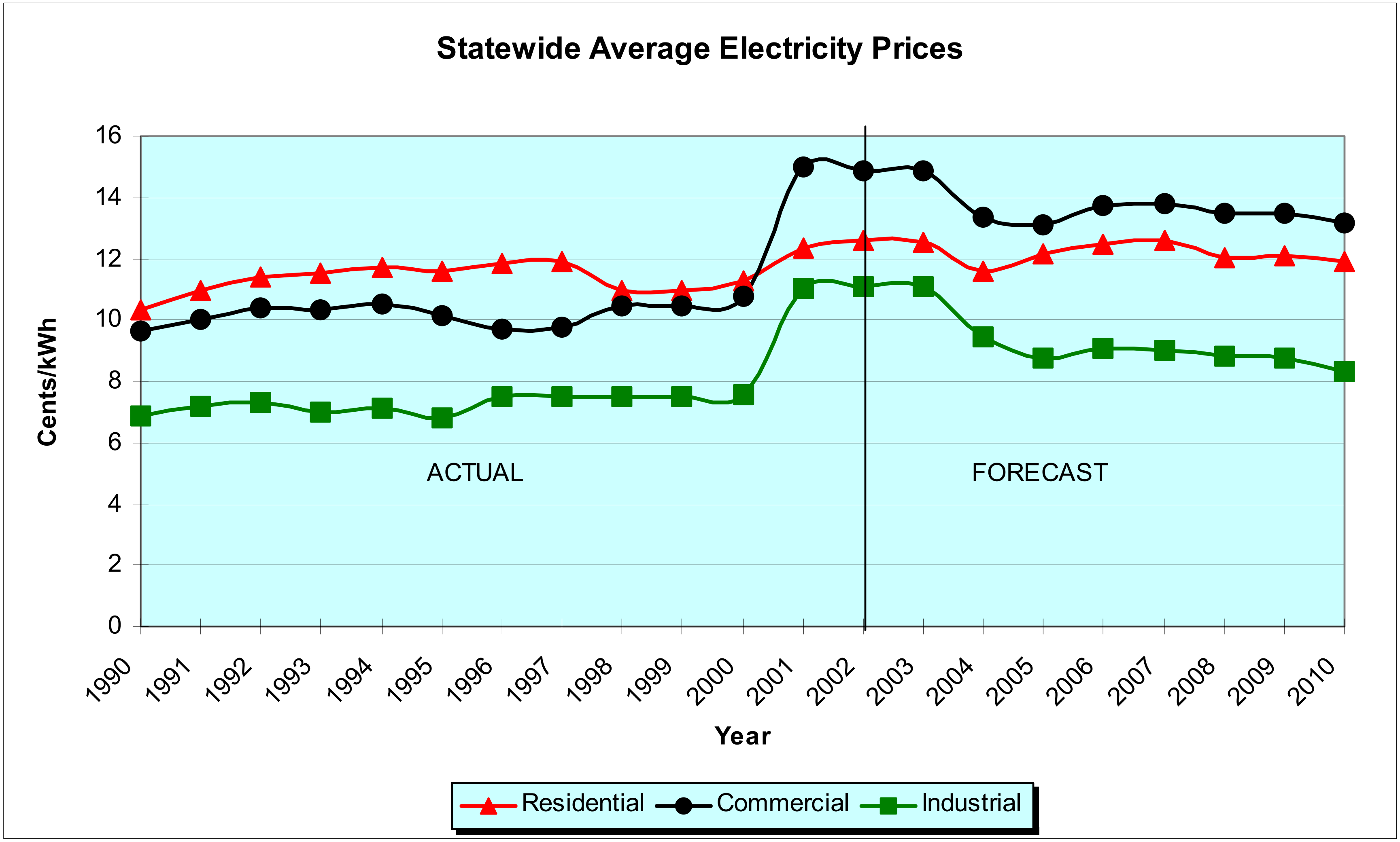
Average Municipal Electricity Prices
¢/kWh Nominal

	Residential	Small Commercial	Medium Commercial	Industrial
2000	9.6	9.8	9.0	8.0
2002	10.1	10.8	9.7	8.2
2005	10.9	11.7	10.4	8.9
2010	15.4	16.4	14.7	12.8

The general shape of the rate impacts, as shown on **Figure 4-1**, is a sharp increase for 2001 through 2003. For residential customers, these rates taper back to previous levels by the decade's end. Commercial rates had a much sharper total increase, and they do not return to previous levels. After the sharp shocks of 2001-2003, the longer impacts will be felt in the commercial and industrial sectors, especially those firms whose electricity costs are a large part of their operations.

The rate impacts will also have an effect on the overall economy. Californians will pay approximately $9 billion more in 2002 than they would have without the crisis. With increased prices lingering through 2007, some decreased consumption will also persist. But, it is not a one-for-one correlation. Historically, electricity consumption is only somewhat responsive to price changes. Marginal uses will be affected, but to the extent that people find electricity use essential to their living conditions or business performance, they will absorb the higher costs. One significant way this may change is if the daily and seasonal structure of the rate is changed to more closely mimic the seasonal and daily pattern of costs of generation.

Figure 4-1
Statewide Rates by Class



Future Prices and Tariffs

Future changes in prices and tariff structures, and the potential load and energy use impacts of those changes, may be more important to the CPA in estimating planning reserve capacity requirements than the short term effects of the 2001 price increases. The current CPUC Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing (R.02-06-001) being conducted jointly with the CPA and Energy Commission will develop the necessary evidence for crafting price responsive tariff designs appropriate to California electricity consumers.

We know little about the magnitude of demand response and energy savings that California consumers might provide under such tariffs. However, experiences in other states provide insight into how dynamic energy prices—prices that vary according to the wholesale price of electricity during incremental time periods—affect demand and how those demand changes fit into reliability planning.

The longest running example of dynamic tariffs is in the Georgia Power service territory. They provide both “day-ahead” and “hour-ahead” real time pricing options for their large industrial and commercial customers. Because the tariffs have been in place since 1992, they have built a body of data sufficient to guide their load forecasts and resource planning activities. Demand response has at times exceeded 800 MW, or close to 5 percent of the utility’s system peak.

For planning purposes, Georgia Power divides the RTP-related demand response into two components: the “load forecast reduction” or “normal RTP response” and the “extreme RTP response”. The first category describes the price response that they observe during periods of relatively stable and predictable pricing. The effects come from customers who have adjusted their usage patterns and equipment investment choices to optimize typical hourly, daily and seasonal price variations. Because their customers respond to these price signals as part of their normal, everyday business activities, their “price-responsive” load and consumption patterns are now a component of their “normal” patterns.

Because their historical demand now includes price-responsive demand, it is incorporated into Georgia Power’s system load forecasts. Their experience is that the reliability of the RTP tariff demand data is equal to demand data from other tariff groups. Although the incorporation of price-responsive demand does not improve or reduce forecasting reliability or the percentage of reserve capacity required, reserve capacity is lower because demand is lower.

The second category, “extreme demand response” refers to the response they have observed from RTP customers during periods when unusual or extreme price events caused the price signal to customers to increase substantially above “normal” prices. In their service area, these were typically caused by forced outages and other system-level emergencies that required the utility to buy power in a tight spot market. In those instances, predictable customer response can double the total RTP demand response. For planning purposes, they treat this predictable demand response as a generation resource for meeting their reserve requirements. In effect, when the utility has to make a supplemental purchase to keep up the spinning reserves, the scarcity rents reflected in market prices are transferred through to RTP customers. In their experience, this response is equal in certainty to a generation resource.

The Impact of Future Tariffs on Load and Consumption Patterns

The actual magnitude of demand response in the California electricity market due to dynamic pricing will depend entirely on the tariff designs and the composition of the electricity customers using those tariffs. What the Georgia Power experience shows is that a properly designed dynamic pricing tariff will lead to predictably lower peak loads than in the absence of such a tariff, which will reduce the amount of reserve capacity required. We also can say that during extreme events that result in substantial price increases, substantial demand response can be predicted with a high degree of certainty.

5. What Impact Will the New Market Design Elements Approved by FERC on 7/17/02 and Those Still Pending Have on System Loads and Procurement Policies?

Poor performance of the initial California market design has led to calls for increased reserve margins to dilute market power. The major changes taking form in California's market design may mean such increases are unwarranted. California is six to twelve months away from establishing the parameters of its revised market design. The four features with the greatest impact on target reserve margins are likely to be locational market pricing, resource procurement, incentives for more rapid transmission development, and inducements for demand response. These changes are expected to create new incentives to enhance supply and reduce demand.

Locational Market Pricing

Locational market pricing could significantly alter prices to loads and the benefits of locating generation on the expensive side of a constraint, depending on the size of the locational nodes and the amount of transmission constraints as well as how the prices are translated into retail rates. For example, PG&E's service area will undoubtedly contain several nodes. The CPUC could well choose to charge retail rates based on the average price of all its nodes (so that low-cost customers subsidize high cost customers). However, a small municipal utility, like Santa Clara, would not have that option, because it would not encompass more than a single node. Its customers would then face the cost at that one node. Thus, customers of municipal utilities located at unfavorable nodes would pay high electricity prices. Generation would have the incentive to locate at high-priced nodes, of course, which would tend to ease transmission constraints, and thus reduce these higher prices over time.

Locational market prices might also increase incentives for energy efficiency, demand response, and distribution generation on the expensive side of the constraint, but not to the extent that RTP would. Most consumers would still see average prices, and not the instantaneous cost of electricity production.

Obligation to Serve

In general, federal and state planners are moving back towards requiring loads to acquire a minimum level of planning reserves. FERC has proposed a minimum value of 12 percent and expects regional bodies to adopt higher levels depending on the unique features of each market design.[5] Within a market context, reserves have to be set at the regional level, because competition among sub-markets will be subject to arbitrage.

[5] FERC Electric Market Design and Structure: Notice of Proposed Rulemaking (RM01-12.000) July 31, 2002 paragraphs 489-490.

Vertically-integrated utilities can set their own planning reserves at whatever level they believe will optimize their ability to meet operating reserve needs at all times.

Market Design Proposals

FERC's Standard Market Design proposal seeks to strengthen transmission capability and to create more common transmission pricing and scheduling practices. Increasing backbone transmission and reducing local transmission constraints will lower the absolute amount of generation and demand response needed to guarantee operating reserves. However, it will also meld sub-regional markets into the larger regional context. This will frustrate any State effort to maintain a reserve level different from those prevalent in the rest of the West. On a positive note, a more fluid transmission network will, in effect, increase the absolute amount of operating reserves available to any sub-region. Power supplies can be used more efficiently if restrictions against "imports" are reduced.

Demand Responsiveness

Price-sensitive demand response could initially either increase or decrease uncertainty regarding the amount of supply necessary to guarantee sufficient operating reserves. This uncertainty should decrease over time, as customers learn how to manage their power needs and demand forecasters learn how to predict responses accurately. So, the degree of demand responsiveness with respect to price should eventually be known with near-certainty. And even if the amount of uncertainty increases in the short term, the amount of supply necessary to guarantee sufficient operating reserves will surely fall.

One important consideration is that demand response may be less expensive than generating facilities are, in part, because it can reduce required reserves. This happens in two ways. First, the California Independent System Operator's Market Analysis Department has argued that planning reserve margins should be set at a higher level to reduce the probability that tight conditions will allow generators to exert market power.[6] Others argue that demand response can be a more effective, less expensive way to reduce the opportunity for generators to exert market power. By using demand response, rather than supply resources, to reduce market-power opportunities, consumers can avoid the cost of a reserve target set above the level that engineering-based assessments would suggest.

Second, price-responsive demand, induced through dynamic tariffs and demand-bidding programs, encourage all participants to reduce demand somewhat when prices are high and supply-demand conditions are tight. As many customers automatically respond to these circumstances by reducing peak load, reserve requirements (which are set at a

[6] CAISO, Department of Market Analysis Study of Reserve Requirements, November 2001.

percent of load) also go down in absolute terms. The state needs to conduct further research and assessment in order to account for the fraction of peak loads that would decline in response to price signals reflecting tight supply-demand conditions.

Clearly, the magnitude of demand response in California will depend on tariff design and the composition of the electricity customers covered by those tariffs. Georgia Power's experience has shown that an effectively designed dynamic-pricing tariff (one form of time-varying prices) leads to predictably lower peak loads than would have occurred in the absence of such a tariff.

Summary

The Energy Commission staff notes that the generation supply outlook has been steadily improving since the crisis began in the fall of 2000, and the status of current construction activities is favorable. Furthermore, while the effects of behavioral conservation efforts have declined over time, conservation investments will persist for many years. Finally, the ongoing proceedings before the CPUC and the FERC will change the market and regulatory structure within which the state's utilities will operate. Among the significant issues before the CPUC is the demand-responsiveness rulemaking that could fundamentally change what constitutes an adequate planning reserve margin.

Recognizing that California has weathered the last two summers with reserves below 15 percent and given the status of ongoing regulatory proceedings and power plant construction, the Energy Commission staff believes that the Power Authority should continue to use a minimum planning reserve target of 15 percent. Once the market structure within which the state will be operating is clear and the utility procurement rules are in place, a reexamination of the Power Authority's target reserve margin will be timely. The Energy Commission staff is prepared to assist in that effort.